DRAFT

CHAPTER 6: ENERGY USE AND END-USE LOAD CHARACTERIZATION

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CHAPTER 6: ENERGY USE AND END-USE LOAD CHARACTERIZATION

6.1 INTRODUCTION

The energy use and end-use load characterization analysis produced energy use estimates and end-use load shapes for distribution transformers. The energy use estimates enabled evaluation of energy savings from the operation of distribution transformer equipment at various efficiency levels, while the end-use load shapes allowed evaluation of the impact on electricity monthly and peak demand from the operation of distribution transformers. The analysis produced a distribution of results for a variety of building types and uses, covering a range of climate locations in order to represent the diversity of use, and performance, of distribution transformers.

The energy use by distribution transformers derives from no-load losses and load losses. No-load losses are constant over time and occur whenever a transformer is energized by power lines. Load losses vary with the square of the load being served by the transformer. Because liquid-immersed transformers are primarily owned by utilities which have marginal electricity generation costs that can vary by the hour, the Department developed a statistical transformer load simulation model to estimate the hourly characteristics of liquid-immersed transformer loads. For dry-type transformers, the Department used empirical estimates of load characteristics to estimate monthly average root mean square (RMS) loads and peak coincident loads for distribution transformers owned by commercial and industrial (C&I) establishments. This chapter first describes transformer losses, and then presents the details of the hourly and monthly end-use load characterization models the Department developed.

6.1.1 Transformer Losses

The energy used by distribution transformers is characterized by two types of losses. The first type are no-load losses that arise primarily from the switching of the magnetic field in the transformer core material. No-load losses are roughly constant and exist whenever the transformer is energized (i.e., connected to live power lines). The second type of losses are load losses which are also known as resistance or I^2R losses. Load losses vary with the load on the transformer and at any point in time are proportional to the load squared plus a relatively small (<15% for loads less than rated load) temperature correction. Considering both load and no-load losses, the Department uses the following formula for estimating the energy used by a distribution transformer:

$$E_{DT}(t) = E_{NL} + E_{LL} \times [Load(t)/(Lrated \times PF)]^2 \qquad \textbf{Eq. 6.1}$$

where:

$E_{DT}(t)$	=	the energy used by the distribution transformer at time *t*,
E_{NL}	=	the no-load losses at rated load,
E_{LL}	=	the load losses at rated load,
$Load(t)$	=	the load served by the transformer at time *t*,
$Lrated$	=	the rated load of the transformer, and
PF	=	the power factor of the load served by the transformer.

6.1.2 Transformer Loading

The key input for estimating distribution transformer energy use is the transformer load. Because the application of distribution transformers varies significantly by type of transformer (liquid-immersed or dry-type) and ownership (electric utilities own approximately 95% of liquid-immersed transformers, commercial/industrial entities use mainly dry-type), the Department performed two separate end-use load analyses to evaluate distribution transformer efficiency. One analysis was designed for liquid-immersed transformers that are used mainly by electric utilities, and the second analysis was designed for dry-type transformers that are used mainly by C&I customers. Sections 6.2 and 6.3 describe these two separate load analyses.

6.2 HOURLY LOAD MODEL

This section describes the hourly load model the Department developed to estimate transformer loads for use in analyzing potential efficiency standards for liquid-immersed transformers.

6.2.1 Overview of Hourly Load Model

The Department estimated hourly loads on individual liquid-immersed transformers using a statistical load simulation model. The statistical load simulation model takes several inputs and performs a statistical simulation for the hourly load on a set of sample transformers. There are five main inputs to the statistical load simulation model:

1. an estimate of the annual peak load;
2. a relationship between peak load and load factor;
3. a relationship between the load factor and the load distribution function;
4. the hourly system load; and
5. the correlation between hourly system load and an individual transformer load.

The Department performed the hourly load simulation with a data-processing program that generated load inputs for the life-cycle cost (LCC) spreadsheet. The Department estimated the annual peak load on the transformer from the rated size of the transformer and a distribution of peak loads that ranged from 50 percent to 130 percent of rated load, with a mean of 85 percent of the rated peak load of the transformer.[a] The Department derived a scaling relationship between peak load and load factor from available hourly load monitoring data. The Department determined a load distribution function with the estimated load factor and simulated the transformer load consistent with the load distribution function. The Department obtained the hourly system loads from the U.S. Federal Energy Regulatory Commission (FERC) and market data from the Independent System Operators for the California, New England, and PJM Interconnection[b] for the year 1999. The Department determined the correlation between transformer load and system load from distributions of correlation coefficients for commercial and residential customers that it derived from available hourly load monitoring data.

The economically important characteristics of transformer loads depend primarily on the load factor, the relationship between peak load and transformer capacity, and the correlation between transformer load and system load.

6.2.2 Hourly Load Simulation Method

The Department developed an hourly transformer load simulation model to capture the varying dynamics and economics of transformer loads. The load simulation program takes utility inputs that include the hourly system loads, hourly prices, or system lambdas (lambda is roughly the marginal operating cost of generation), and then simulates a distribution of customer loads. The program provides summary data on customer loads, costs, and prices as output.

Simulation of customer or building loads is a common method for estimating building energy use when specific monitoring data are not available. A statistical simulation takes information on the mathematical and statistical characteristics of building loads and performs a Monte Carlo simulation to produce sets of building loads that have the same mathematical and statistical characteristics as measured building data. A Monte Carlo simulation is a computer

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[a] If transformers are sized for moderate load growth on average (for example, 1 percent annual growth over 30 years), then the average peak loading should be somewhat below the rating stated on the nameplate. The Department modeled the initial peak loading of liquid-immersed transformers in the hourly load model with a smooth distribution with a minimum peak loading of 50 percent of nameplate, a median of 85 percent of nameplate, and a maximum 130 percent of nameplate. The median value selected by the Department provides some room for load growth while utilizing the ability of the transformer to tolerate temporary loads greater than nameplate in the later years of the transformer's lifetime. The Department assumed a fairly wide range of initial peak loadings for liquid-immersed transformers and an average initial peak loading of 85 percent

[b] PJM coordinates the movement of electricity in all or parts of Delaware, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia, and the District of Columbia.

calculation with a built-in random process that estimates the probability of different results. With regard to the economics of energy use by transformers, the most important mathematical characteristics of the building loads are their size relative to the transformer capacity, their variation, and their correlation with system loads and prices.

The Department determined the values used for customer load variability, and customer load correlation with system loads, by analyzing available hourly building load data. In more detail, the specific steps in the operation of the hourly load simulation program are as follows:

1. The program selects a utility from a database of utilities that publicly report system load and system lambda data.
2. The program determines a sample weight for the utility, based on total kilowatt-hour (kWh) sold.
3. The program selects the capacity for the transformer, based on the design line.
4. The program selects the transformer peak load relative to the transformer capacity, and the corresponding weight from a transformer peak load distribution.
5. The program selects the transformer load factor based on the peak load versus inverse load factor distribution. The program calculates the characteristics of the load factor distribution from End-Use Load and Consumer Assessment Program (ELCAP) data.[1]
6. The program selects the customer type served by the transformer and the appropriate weight for that customer type. The program selects the relative customer weight from the fraction of electricity sales to the customer type for the particular utility.
7. From the transformer inverse load factor estimate, the program calculates the load distribution function. The load distribution function in the program is an exponential function with the selected inverse load factor.
8. Based on the customer type served, the program selects the (rank order) correlation with system load, based on correlation coefficient distributions calculated from hourly load data.
9. The program then calculates the hourly system load rank orders for each hour of the year by sorting the hourly system load values for the year and assigning a rank to each.
10. The program calculates the hourly transformer load rank orders by adding the appropriate random variation to the system rank order to produce transformer rank orders with the selected rank order correlation. The program normalizes the rank orders of the transformer load so that they are evenly distributed between 1 and 8760, inclusive.
11. The program calculates the hourly transformer load from the simulated hourly transformer rank order. This calculation uses the cumulative transformer load-probability function, which is an integral of the load-distribution function.
12. The program then calculates the coefficients of a Fourier representation of the transformer load shape for each day type (i.e., weekday, weekend, and peak day). It then makes the same calculation for the load-square weighted price curves which are a function of day type, hour, and the month of the year.

13. The program provides output for use in the LCC spreadsheet in the form of tab-separated values. These data contain a customer load identification (ID), transformer characteristic, the utility ID, summary statistics on price and load, and load and price shape coefficients.

6.2.3 Hourly Load Simulation Inputs

The inputs used in the hourly load simulation are described in the following sections.

6.2.3.1 Utility Sample

The utility sample is the subset of electric utilities in the Nation whose economic and load data are represented in the hourly load analysis. In the hourly load analysis for liquid-immersed transformer designs, the Department began with hourly system load and economic data from the Nation's electric utilities. The Department compiled the full list of the Nation’s electric utilities by combining all utilities that report retail data using DOE's Energy Information Administration's (EIA) Form 861,[2] with utilities that reported data in FERC Form 1,[3] and utilities that are listed in the FERC Form 714[4] respondent list. The Department included a utility in its hourly load simulation sample if the utility reported distribution transformer data in FERC Form 1 for the year 2000, and if sufficient information was available to characterize the utility's load and hourly marginal electricity costs, either from FERC Form 714 data or from the relevant electricity market. Table 6.2.1 shows the list of 80 utilities that satisfy all of these data requirements.

Table 6.2.1 Utility Sample for Hourly Load Simulation Data

EIA Code*	NERC Region**	Name
296	SPP	Alfalfa Electric Coop Inc.
733	ECAR	Appalachian Power Co.
963	MAAC	Atlantic City Electric Co.
1167	MAAC	Baltimore Gas & Electric Co.
1179	NPCC	Bangor Hydro-Electric Co.
1796	NPCC	Blackstone Valley Electric Co.
1998	NPCC	Boston Edison Co.
2886	NPCC	Cambridge Electric Light Co.
3292	NPCC	Central Vermont Pub Serv Corp.
3266	NPCC	Central Maine Power Co.
3597	MAAC	Citizens Electric Co.
4062	ECAR	Columbus Southern Power Co.
4110	MAIN	Commonwealth Edison Co.
4089	NPCC	Commonwealth Electric Co.
4148	NPCC	Concord Electric Co.
4184	NPCC	Connecticut Valley Elec. Co. Inc.
4176	NPCC	Connecticut Light & Power Co.
4254	ECAR	Consumers Energy Co.
5027	MAAC	Delmarva Power & Light Co.
5109	ECAR	Detroit Edison Co.
5416	SERC	Duke Energy Corp.
5487	ECAR	Duquesne Light Co.

* The EIA Code is the unique identification number assigned by EIA to companies and entities operating in the electric power industry.
** The North American Electric Reliability Council (NERC) regions, in the order they appear in this utility sample, are: Southwest Power Pool (SPP), East Central Area Reliability Coordination Agreement (ECAR), Mid-Atlantic Area Council (MAAC), Northeast Power Coordinating Council (NPCC), Mid-America Interconnected Network, Inc. (MAIN), Southeastern Electric Reliability Council (SERC), Mid-Continent Area Power Pool (MAPP), Western Electricity Coordinating Council (WECC), Electric Reliability Council of Texas, Inc. (ERCOT), and Florida Reliability Coordinating Council (FRCC). FERC provides load and lambda data in files organized by NERC region.

Table 6.2.1 Utility Sample for Hourly Load Simulation Data (continued)

EIA Code*	NERC Region**	Name
5389	NPCC	Eastern Edison Co.
5659	ECAR	Edison Sault Electric Co.
5860	SPP	Empire District Electric Co.
13478	SPP	Entergy New Orleans Inc.
814	SPP	Entergy Arkansas Inc.
7806	SPP	Entergy Gulf States Inc.
11241	SPP	Entergy Louisiana Inc.
12685	SPP	Entergy Mississippi Inc.
6077	NPCC	Exeter & Hampton Electric Co.
6342	SPP	First Electric Coop Corp.
6374	NPCC	Fitchburg Gas & Elec. Light Co.
26510	NPCC	Granite State Electric C.o
7601	NPCC	Green Mountain Power Corp.
9162	MAPP	IES Utilities Inc.
9324	ECAR	Indiana Michigan Power Co.
9392	MAPP	Interstate Power Co.
9726	MAAC	Jersey Central Power & Light Co.
22053	ECAR	Kentucky Power Co.
10331	ECAR	Kingsport Power Co.
11118	SERC	Lockhart Power Co.

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Table 6.2.1 Utility Sample for Hourly Load Simulation Data (continued)

EIA Code*	NERC Region**	Name
11804	NPCC	Massachusetts Electric Co.
12390	MAAC	Metropolitan Edison Co.
12341	MAPP	MidAmerican Energy Co.
12796	ECAR	Monongahela Power Co.
13214	NPCC	Narragansett Electric Co.
13407	WECC	Nevada Power Co.
13441	NPCC	New Hampshire Elec Coop Inc.
13549	NPCC	Newport Electric Corp.
13781	MAPP	Northern States Power Co.
13780	MAPP	Northern States Power Co.
14006	ECAR	Ohio Power Co.
14063	SPP	Oklahoma Gas & Electric Co.
14328	WECC	Pacific Gas & Electric Co.
14940	MAAC	PECO Energy Co.
14711	MAAC	Pennsylvania Electric Co.
15270	MAAC	Potomac Electric Power Co.
15263	ECAR	Potomac Edison Co.
15466	WECC	Public Service Co. of Colorado
15473	WECC	Public Service Co. of NM
15472	NPCC	Public Service Co. of NH

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** The North American Electric Reliability Council (NERC) regions, in the order they appear in this utility sample, are: Southwest Power Pool (SPP), East Central Area Reliability Coordination Agreement (ECAR), Mid-Atlantic Area Council (MAAC), Northeast Power Coordinating Council (NPCC), Mid-America Interconnected Network, Inc. (MAIN), Southeastern Electric Reliability Council (SERC), Mid-Continent Area Power Pool (MAPP), Western Electricity Coordinating Council (WECC), Electric Reliability Council of Texas, Inc. (ERCOT), and Florida Reliability Coordinating Council (FRCC). FERC provides load and lambda data in files organized by NERC region.

Table 6.2.1 Utility Sample for Hourly Load Simulation Data (continued)

EIA Code*	NERC Region**	Name
15477	MAAC	Public Service Electric & Gas Co.
8901	ERCOT	Reliant Energy HL&P
17535	MAPP	South Beloit Water Gas & Elec. Co.
17539	SERC	South Carolina Electric & Gas Co.
17609	WECC	Southern California Edison Co.
17633	ECAR	Southern Indiana Gas & Elec. Co.
17718	SPP	Southwestern Public Service Co.
18454	FRCC	Tampa Electric Co.
24211	WECC	Tucson Electric Power Co.
19497	NPCC	United Illuminating Co.
19840	WECC	Valley Electric Assn. Inc.
19876	SERC	Virginia Electric & Power Co.
20387	ECAR	West Penn Power Co.
20455	NPCC	Western Massachusetts Elec. Co.
20521	ECAR	Wheeling Power Co.
20856	MAPP	Wisconsin Power & Light Co.
20847	MAIN	Wisconsin Electric Power Co.
20860	MAIN	Wisconsin Public Service Corp.

* The EIA Code is the unique identification number assigned by EIA to companies and entities operating in the electric power industry.
** The North American Electric Reliability Council (NERC) regions, in the order they appear in this utility sample, are: Southwest Power Pool (SPP), East Central Area Reliability Coordination Agreement (ECAR), Mid-Atlantic Area Council (MAAC), Northeast Power Coordinating Council (NPCC), Mid-America Interconnected Network, Inc. (MAIN), Southeastern Electric Reliability Council (SERC), Mid-Continent Area Power Pool (MAPP), Western Electricity Coordinating Council (WECC), Electric Reliability Council of Texas, Inc. (ERCOT), and Florida Reliability Coordinating Council (FRCC). FERC provides load and lambda data in files organized by NERC region.

The hourly load model uses data from each utility as a basis for the hourly simulation and valuation of transformer loads in that utility. The Department statistically simulated a set of transformer loads for each utility that were correlated with the utility's hourly system load. The

Department also calculated average hourly price profiles using hourly system lambdas (or market prices). The Department weighted the prices by the square of the statistically simulated transformer load to calculate average prices (since load losses are proportional to the square of the load on the transformer).

6.2.3.2 Customer Type

The Department used the data on electricity sales by customer classes reported in EIA Form 861 to characterize the different types of customer loads as residential, commercial, or industrial. The customer type for a transformer is the class of customers whose loads are served by the transformer.

The data simulation model for hourly loads is a Monte Carlo simulation. This means that the Department sampled transformer and customer characteristics from probability distributions using a random number generator. The results of the simulation are output with weights that are proportional to the probability of the computed result. In the hourly load simulation, the Department selected the customer type for the transformer after it had selected the sample utility. The Department simulated an equal number of sample transformers for each customer type and each utility. The Department then assigned a weight to each sample transformer in the simulation that represented the population of transformers represented by that sample. The assignment of customer-type weights assumed that the population of transformers for each customer type is roughly proportional to the electricity sales to that customer type.

6.2.3.3 Transformer Initial Peak Loading

The Department used a distribution of initial peak loading values to characterize the annual peak load served by each transformer in its simulation. The transformer initial peak loading is the ratio of the transformer peak load in the first year of operation to the rated load of the transformer. The Department selected a distribution of initial peak loadings with a median of 85 percent, a minimum of 50 percent and a maximum of 130 percent. Standard engineering practice for sizing distribution transformers selects a transformer based on the expected annual peak of the load being served, with some provision made for load growth. Because of the provision for load growth, initial peak loading will usually be less than 100 percent. However, in practice, there is also some error in estimating the annual peak load that will be served by a transformer, and engineers generally use a discrete set of transformer ratings that are imperfectly matched with the expected peak load. Distribution transformers generally are manufactured in discrete kilovolt-ampere (kVA) ratings and, on average, the next larger kVA rating is 50 percent larger than the previous kVA rating (measured relative to the smaller size). An initial peak loading as high as 130 percent can occur because transformers can be loaded for short periods to levels of more than 130 percent of nameplate capacity.[5] Figure 6.2.1 illustrates the distribution of initial peak loading the Department used.

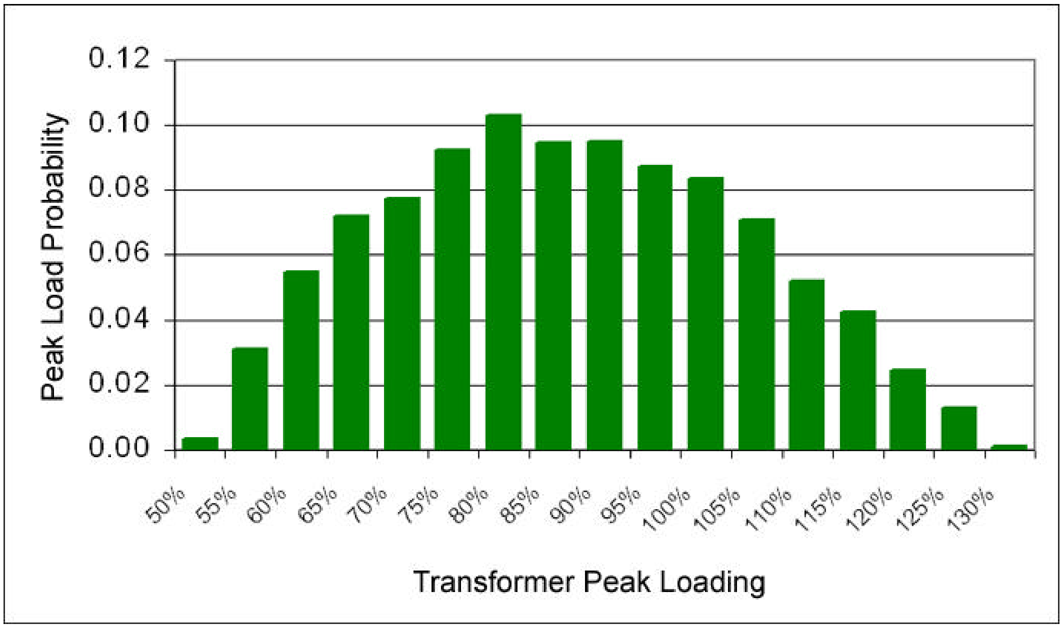

Figure 6.2.1 Histogram of the Peak Loading Distribution Generated in the Hourly Load Analysis

6.2.3.4 Load Factor and Inverse Load Factor

The load factor is the ratio of the average load to the peak load. Inverse load factor is the ratio of the peak load to the average load. The transformer load simulation provides hourly simulated loads using a distribution of load factors that depends on the initial peak load. Consistent with data on electrical customer loads, transformers serving larger annual peak loads tend to serve loads with larger load factors.

The load factor of customer and transformer loads has a wide range of variation, but correlates with the average size of the load and the annual peak load. The initial annual peak load on a transformer is the product of the transformer initial peak loading, the transformer capacity, and the power factor, assumed to be 1 W/kVA.

The Department analyzed hourly load data from ELCAP and confirmed its results with confidential utility data to develop an aggregate distribution that models the inverse load factor as a function of annual peak load. The Department fit a power-law regression to the relationship between inverse load factor and peak load. The power-law regression produced the following equation for inverse load factor as a function of peak load:

$$InvLoadFact = 1 + 9.59 \times (PeakLoad)^{-0.418} \qquad \textbf{Eq. 6.2}$$

Figure 6.2.2 shows a scatterplot of the inverse load factor-versus-peak load relationship. The figure plots both the ELCAP data and the regression function used to relate inverse load factor and initial peak loading for the hourly load model that the Department used for liquid-immersed transformers. Also shown is the plot of the regression equation used to model inverse load factor as a function of peak load for the hourly load model.

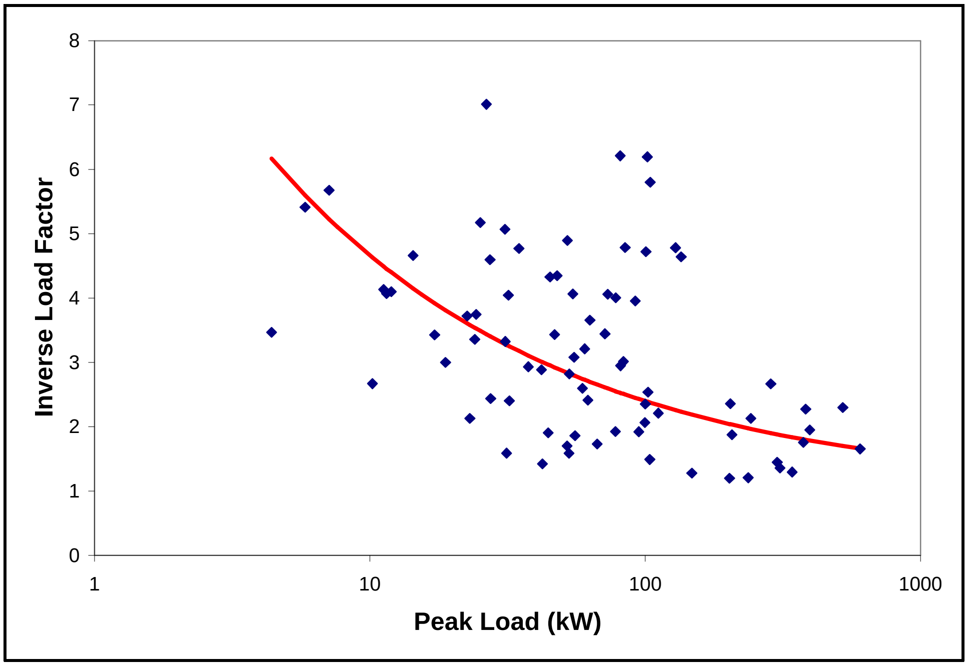

Figure 6.2.2 Scatterplot of Inverse Load Factor versus Peak Load from Hourly ELCAP Data

6.2.3.5 Load Distribution Function

The load distribution function determines the probability that a customer load (transformer load) will be a particular value during some hour of the year. The Department ensured that the simulated transformer load has a specified load factor by selecting a consistent load distribution function. A consistent load function is one that can be mathematically shown to result in loads with the given load factor. In the simulation, the Department calculated hourly loads using the selected load distribution function.

The Department approximated the load distribution function with a one-parameter exponential fit that depended on the load factor. Specifically, the Department used a load selected from a function of the normalized load: *Load/Lmax*, where *Lmax* is the annual maximum load. The following three equations define the load distribution function:

$$LoadProb = BLoad \times (exp(-ALoad \times Load/Lmax))\ when\ Load/Lmax < x_0 \qquad \textbf{Eq. 6.3}$$

$$LoadProb = CLoad \times (exp(-DLoad \times (Load/Lmax - x_0)))\ when\ Load/Lmax > x_0, \qquad \textbf{Eq. 6.4}$$

$$LoadProb = 1/8760\ when\ Load/Lmax = 1 \qquad \textbf{Eq. 6.5}$$

The function is continuous, and *ALoad*, *BLoad*, *CLoad*, and *DLoad* are constants. The variable x_0 is a parameter that defines when the load probability function (*LoadProb*) begins decreasing rapidly to the value of 1/8760. The Department selected the approximate value of x_0 by examining the load distribution functions from available hourly load data. *Lmax* is the maximum or peak annual load. The constants are determined by the following conditions:

1. The integral from 0 to 1 of *LoadProb* with respect to *Load/Lmax* is 1;
2. The inverse load factor is set to a particular, given value;
3. The load probability function is continuous; and
4. *LoadProb(1)* = 1/8760.

The load distribution function is, therefore, a probability function of *Load/Lmax* that depends on the parameters of inverse load factor and the constant parameter x_0. For each transformer in the hourly simulation model, once the Department selected the inverse load factor for the transformer, the values of *ALoad*, *BLoad*, *CLoad*, and *DLoad* were calculated given the four conditions that the probability function satisfies. The Department selected the value of the turning-point parameter x_0 as 0.95, based on examination of load distribution functions from the ELCAP hourly load data. On a logarithmic scale, the empirical load distribution functions showed a point at which they would descend rapidly toward the value of 1/8760 at *Load/Lmax* = 1.

6.2.3.6 Hourly System Load

The hourly system load is the hourly load in the control area or electricity market where the transformer is located.

Electricity hourly load and cost data come from FERC and electricity market web sites. The source of data for regulated utilities was FERC Form 714,[4] which provides data on hourly system loads, hourly system lambdas, and forecasts of peak demand for transmission control areas. In a control area, there is usually "one electric utility charged with operating the control area" and other utilities "which are bound together through pooling contracts, holding company operations or other contractual arrangements" (see: http://www.ferc.gov/docs-filing/eforms/form-714/instructions.asp). Each utility with a planning area that has an annual peak demand greater than 200 megawatts must file Form 714. The system lambda file in Form 714 is derived from the economic dispatch function associated with automatic generation control. It is the incremental fuel cost for a set of on-line and loaded thermal generating units "when each unit is loaded and operating at the same incremental fuel cost ($/MWh) with the sum of the unit loadings (MW) equal to the system demand plus the net of interchange with other control areas." The Department used the system lambda as the marginal fuel cost of electricity for regulated utilities.

For utilities that sell into regional electricity markets, the hourly system load and electricity cost data are obtained from the Independent System Operator of that market. These data include both the actual system load and the hourly market price.

For electricity markets, the system load is the "Actual System Load" as published by the operator of that market. The Department used the actual market system load as the system load for utilities in areas where there are electricity markets. The Department assumes that the marginal wholesale electricity economics of a utility are characterized by the economics shown in the local control area or electricity market. This assumption means that some geographically small-scale variations in electricity economics may not be captured in the analysis.

6.3 MONTHLY LOAD MODEL

This section describes the model the Department developed to estimate monthly transformer loads for use in analyzing potential efficiency standards for dry-type distribution transformers, which are owned mainly by C&I entities.

6.3.1 Overview of Monthly Load Model

For dry-type transformers, the Department developed a monthly load model that estimates the impacts of transformer loads and resultant transformer losses on the monthly electricity usage, demand, and electricity bills of customers.

Transformer losses have a constant loss component (the no-load or core losses) and a loss component that depends on the square of the load on the transformer (the load or coil losses). The economic value of transformer losses is a function of the load on the transformer and the timing of the load with respect to variable energy costs and peak demand. To the extent there is a correlation between transformer losses and variable energy costs, then the cost of the electricity supplying the transformer losses will be different from the average cost of electricity. The LCC analysis for dry-type transformers estimated the economic impact of losses by estimating changes in monthly peak demand and the corresponding demand charges for C&I customers.

6.3.2 Monthly Load Estimation Steps

The Department used monthly load estimates to calculate the LCC savings due to efficiency standards for dry-type distribution transformers. Commercial and industrial customers are usually billed for electricity according to monthly demand, usage, and fixed charges. There are a great variety of electricity tariff structures, including time-of-use rates and real-time prices, that are used for billing electricity to C&I customers. For simplicity in estimating the monthly bills for C&I customers, the Department used only the commercial tariffs that have monthly demand, usage, and/or fixed charges in the tariff formula (this process is described in more detail in section 8.3.5.2). Load estimates of monthly customer usage and demand are inputs to the bill calculator in the LCC analysis.

To estimate the impact of transformer losses on C&I electricity bills, the Department modeled the relationship between monthly transformer load characteristics and customer demand and usage. The model used by the Department estimates the load factor, coincident peak load, and RMS load on the transformer, relative to the total customer load. The Department derived distributions of load parameters from hourly load data from ELCAP and confirmed the results with proprietary utility data. It used these same load-parameter distributions as inputs to estimate the monthly transformer energy and coincident peak demand losses. When used as inputs into a monthly electricity bill calculator, monthly transformer energy demand and energy increments provide the estimate of monthly bill impacts for transformer owners.

The Department took the following steps in calculating the monthly load:

1. The Department obtained a statistical sample of monthly demand and usage data for C&I buildings from the Energy Information Administration (EIA)'s 1995 *Commercial Building Energy Consumption Survey* (CBECS)[6] and other data sources.
2. The Department estimated an annual peak transformer load from a transformer peak loading distribution, derived from an estimate of the impacts of conservative transformer sizing practice that tends to over-size distribution transformers.
3. The Department estimated the load factor (i.e., the ratio of the average load to the annual peak load) of the load on the transformer from load factor distributions found in CBECS.
4. The Department derived distributions for the ratio of the RMS load to the average load as a function of the transformer load factor, through an analysis of hourly building load data.
5. The Department estimated monthly peak transformer load and monthly RMS transformer load by scaling annual peak transformer values. The scaling estimates monthly values of transformer peak and RMS load as being proportional to customer monthly demand and energy usage data, respectively.

6. Using an analysis of available hourly building load data, the Department estimated a transformer peak responsibility factor (PRF) distribution that is a function of load factor.
7. The Department applied the average PRF to monthly transformer peaks to estimate monthly transformer demand.
8. The Department's model calculates incremental monthly customer usage and demand from no-load and load loss coefficients, transformer RMS load, and transformer coincident peak load in the LCC spreadsheet.

6.3.3 Monthly Load Model Inputs

The monthly load model inputs are:

- customer demand and usage data
- customer sampling weights
- initial peak load
- transformer load factor
- root mean square load to average load ratio
- transformer peak responsibility factor

6.3.3.1 Customer Demand and Usage Data

Customer demand and usage are the monthly peak load and electrical energy consumption, in units of kilowatts and kilowatt-hours, respectively. Usage is sometimes also called energy, or consumption. The Department used these data to calculate the base monthly customer electricity bills that may be affected by changes in transformer efficiency. Commercial and industrial customers may have many distribution transformers on their premises. An individual transformer will make an incremental impact on the customer electricity bill by making incremental changes in the customer demand and usage.

For commercial customers, the Department obtained a statistically representative sample of monthly customer demand and usage from data collected in the 1995 CBECS. The Department did not have at its disposal a sample of monthly demand and usage data for industrial customers. The Department applied the CBECS commercial customer monthly data to estimate the monthly bills for industrial customers by adjusting the customer weights to compensate for the larger size and the corresponding larger load factors of industrial customers.

The Department assumed that monthly demand and usage for larger industrial and large commercial customers are similar. It verified this assumption by comparing load factor distributions for C&I customers for a utility in the southeastern U.S. The Department found that the differences between customer classes were much smaller than the variability within each class, although the average load factor for groups of industrial customers with peak loads less than 500 kW can be 0–30 percent less than the load factor for commercial customers with the same annual peak load. The Department explored the potential impact of this assumption on the analysis by examining the sensitivity of the LCC results to changes in the average transformer loading.

6.3.3.2 Customer Sampling Weights

The customer sampling weight is a number that is proportional to the probability that a particular customer sample will be selected during a national LCC calculation. It should be proportional to the probability that a transformer of a particular design line may be owned by a customer with load characteristics similar to the customer sample data. The Department adjusted the sample weights for commercial customers provided by CBECS to produce sample weights for equivalent industrial customers and to ensure that customers with loads too small for a particular transformer design were not included. The Department adjusted the CBECS weights by a power of the customer load to produce a distribution of customers that has the same average load as industrial customers. The Department assigned a zero weight to those customers who had an average demand less than the transformer capacity.

To produce a distribution of monthly demand and usage data to represent industrial customers, the Department examined the EIA's Form 861 data[2] from 1995 to calculate the average size ratio between industrial and commercial customers for 1995. The Department found that, on average, industrial customers had loads that were 26.2 times larger than those of commercial customers in 1995. Then for the CBECS distribution of customers, for those buildings with monthly usage and demand data, the Department constructed a new set of weights that had the same total sum, but which had an average load 26.2 times larger than the CBECS distribution. It constructed the new distribution by multiplying the CBECS weight by a power of the average load of the CBECS customer. The Department chose the power to provide the desired change in average customer size.

Since the Department estimated that 60 percent of dry-type transformers go into commercial buildings, while 40 percent go into industrial buildings, it used a 60/40 weighted average of the C&I building weights for the total building weight, when the average building demand is larger than the transformer capacity. If the average building demand is less than the transformer capacity, then the CBECS data for that building have no weight or influence on the LCC calculation. This is because dry-type transformers are typically used for customer component loads for particular circuits or equipment. These circuits have demand that is less than the total building demand, and the transformers for the circuits are sized to meet this smaller demand.

The approach that the Department took was based on the fact that, when the transformer is larger than the entire customer demand, the customer will own the transformer. In addition, the Department believes that the load characteristics of industrial customers are similar to those of large commercial customers.

6.3.3.3 Initial Peak Load

Initial peak load is the annual, per-unit peak load on the transformer during the first year of operation. The initial peak load is estimated as a percentage of the rated peak load of the transformer. The Institute of Electrical and Electronics Engineers, Inc. (IEEE) *Draft Guide for Distribution Transformer Loss Evaluation*[7] defines a similar but distinct measure of peak transformer loading called an "Equivalent Annual Peak Load" that accounts for changes in peak load over the life of the transformer. IEEE's *Draft Guide* refers to the initial peak loading as "Initial Transformer Loading" and uses values of 0.9 and 0.95 in its example calculations.

Rather than use the equivalent annual peak load method, the Department accounted for annual changes in peak load by applying an annual rate of change in transformer load in the LCC calculation to account for year-to-year changes in transformer load. The Department characterized a range of possible initial peak loads by defining a distribution of initial peak loads.

Distribution transformers generally are manufactured in discrete kVA ratings representing their power handling capacity. On average, the each kVA rating is 50 percent larger then the previous kVA rating (measured relative to the smaller rating). Transformers can be loaded above their kVA rating (or "nameplate capacity") for short periods of time. However, transformers are often sized conservatively to avoid the possibility of an overload. The initial peak load on a transformer ranges from 60 percent to 90 percent if electrical engineers accurately size dry-type transformers conservatively with a 10 percent safety margin relative to the nameplate capacity. The high end of the range, i.e., 90 percent initial peak loading, is the maximum initial peak load with a 10 percent safety margin. The low end of the range of 60 percent initial peak loading reflects the threshold peak load where a smaller kVA rating can be selected with 90 percent peak loading. The Department therefore selected a distribution for the initial peak load that has a constant probability between 60 percent and 90 percent of nameplate capacity.

The Department believes that, in selecting an appropriate kVA rating for an application, engineers choosing dry-type transformers are conservative and do not take advantage of the fact that transformers can be safely overloaded for short periods of time. The National Electrical Code[8] encourages conservative transformer sizing behavior by requiring a transformer that is serving a secondary circuit of less than 600 V to be rated at not less than 80 percent of the total amperage of the secondary circuit protection (Table 450.3(A) of the Code).

6.3.3.4 Transformer Load Factor

The transformer load factor is the ratio of the average load to the annual peak load. To estimate the load factor on the transformer, the Department examined the load factors of the loads in the CBECS 1995 monthly building demand and usage data and derived distributions consistent with these data. Figure 6.3.1 shows an aggregate histogram of the load factors from these data, for those buildings with both demand and usage data.

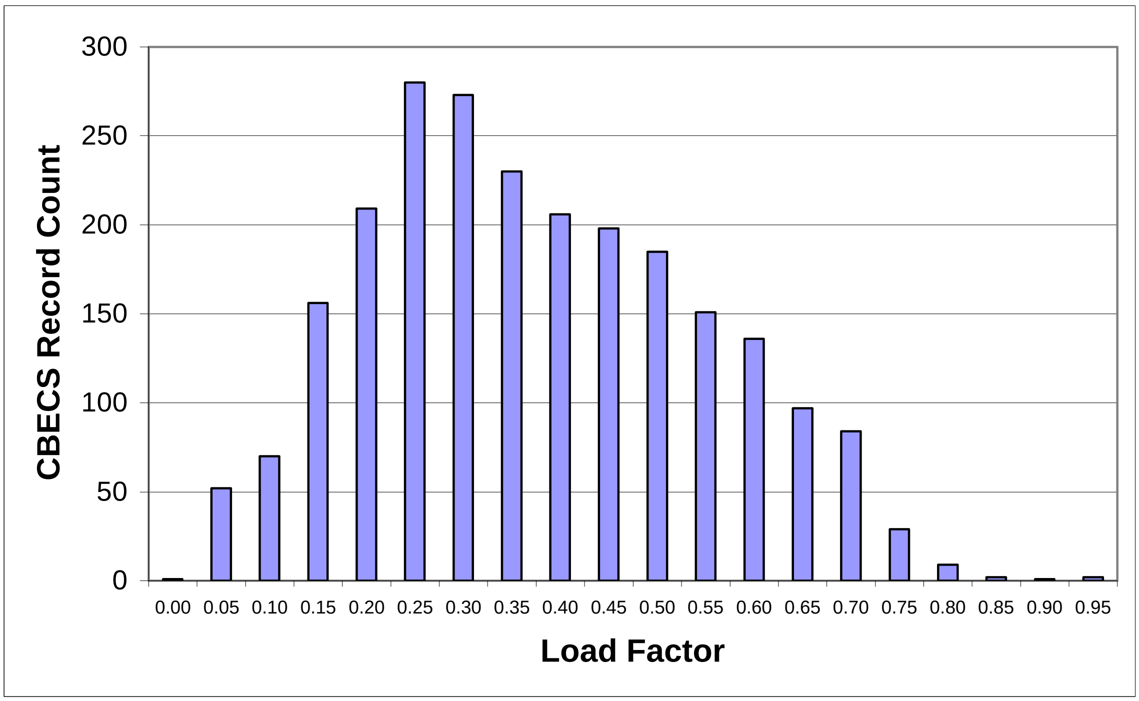

Figure 6.3.1 Histogram of Annual Load Factors Derived from Monthly CBECS 1995 Bill Data

From Figure 6.3.1, the Department estimated that the minimum load factor is approximately 0.01 and the maximum load factor is approximately 0.85, with only a few data points outside this range. The Department modeled the distribution of transformer load factors as a triangular probability distribution with the values of 0.01 and 0.85 as the minimum and maximum of the distribution, respectively. The Department set the maximum probability point of the triangular distribution at 0.32 so that the mean load factor of the triangular distribution matched the mean load factor of the CBECS data.

Available data indicate that for buildings, load factors increase with increasing peak load on average. This relationship is due to diversity effects, where the fluctuations of many smaller loads tend to average out over time, such that the relative fluctuations in the sum of many individual loads is smaller that the relative fluctuations in the sum of a few individual loads. The variation of the load factor with the annual peak demand is illustrated in Figure 6.3.2 for the CBECS 1995 buildings that have both monthly usage and demand data. The relationship between load factor and peak load illustrated here is insensitive to whether monthly or annual data are used. The Department used the following equation to model the relationship between annual peak load and mean load factor:

$$LF = 0.0504Ln(x) + 0.1212 \qquad \textbf{Eq. 6.6}$$

where:

Ln	=	the natural logarithm,
x	=	the annual peak load, and
LF	=	the load factor.

Figure 6.3.2 also shows the logarithmic fit to the load factor/annual demand relationship for the CBECS data.

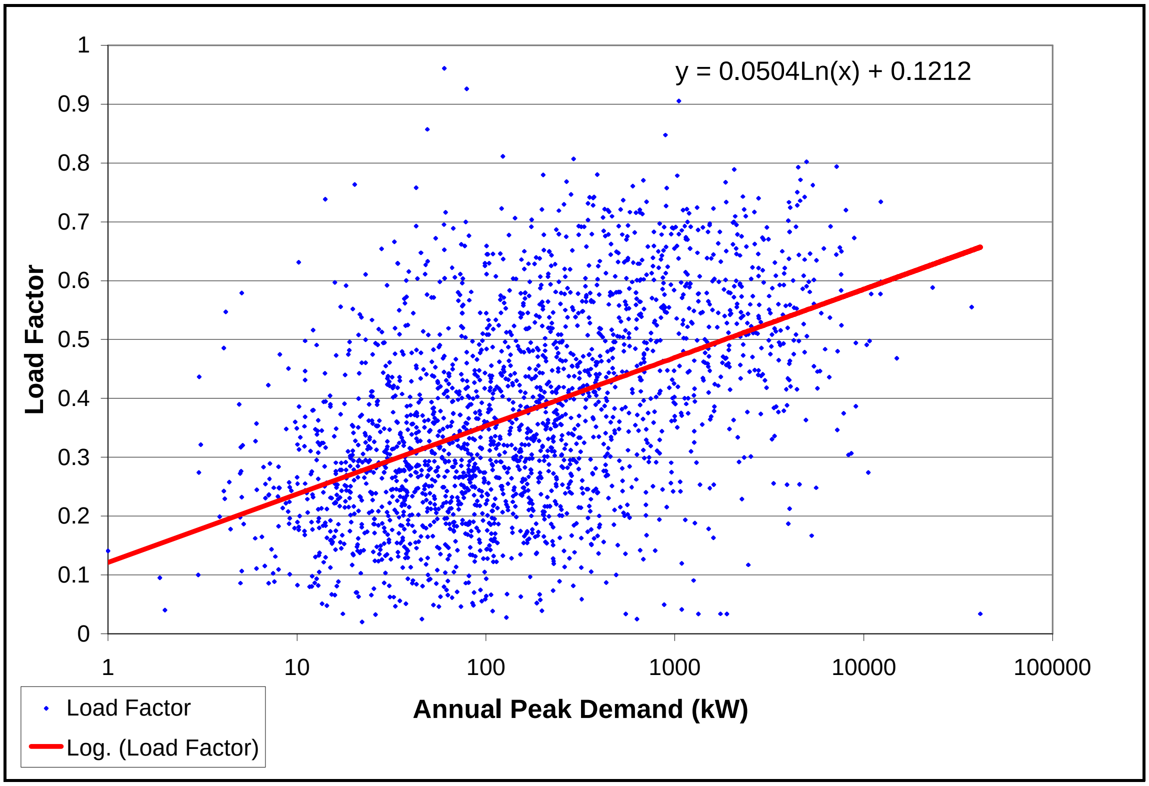

Figure 6.3.2 Scatterplot of Annual Load Factor versus Annual Peak Demand from Monthly CBECS 1995 Bill Data

Application of this analysis to the estimation of transformer load factors assumes that the statistical behavior of transformer loads is similar to the statistical behavior of whole building loads.

6.3.3.5 Root Mean Square-to-Average Load Ratio

The root mean square-to-average load ratio is the ratio of the root mean square (RMS) load on the transformer to the average load on the transformer. Distribution transformer load losses are proportional to the square of the RMS load on the transformer. For loads with large amounts of variability, the RMS and the average load on the transformer may be significantly different. The Department analyzed hourly load data in order to characterize the ratio of the RMS load to the average load on the transformer. This characterization included an estimate of the variability in the RMS-to-average load ratio, and the dependence of this ratio on the load factor of the load being served by the transformer.

The Department analyzed both older, public data from an ELCAP study of hourly electrical loads in the Northwest in 1987 and 1988[9] and more recent (proprietary) hourly load data from the Southeast from 1998, 1999, and 2000. The Department found consistent behavior between ELCAP commercial building loads and both industrial and commercial loads from the more recent southeastern data. The Department found the differences between the average RMS/average load ratios from the data sets to be less than 10 percent.

The Department found that the RMS-to-average load ratio depended on the load factor. The Department fit the relationship between load factor and (RMS/Avg -1) to an exponential trend line with an R-square of 0.8. This relationship can be expressed by the following equation:

$$(RMS/Avg - 1) = 1.4 \times e^{-7*LF} \qquad \textbf{Eq. 6.7}$$

where:

RMS/Avg	=	the ratio of the RMS load to the average load, and
LF	=	the annual load factor.

In its treatment of RMS-to-average load ratios, the Department assumed that:

1. The statistical behavior of a set of whole-building loads of a given average load is similar to the statistical behavior of a set of individual transformer loads with the same average load;
2. The RMS load analyzed from hourly data is the same as the RMS load analyzed from data of higher time resolution (in reality, RMS values from higher-time-resolution data may be higher than RMS values from hourly data); and

3. The load losses on the transformer vary as the square of the load being served by the transformer.

In this part of the analysis, the Department made no assumptions about the load factor of the load being served by the transformer, but only estimated the relationship between load factor, average load, and RMS load.

6.3.3.6 Transformer Peak Responsibility Factor

The transformer PRF is the square of the ratio of the transformer load at the time of the customer peak load to the transformer peak load. The PRF of a load depends on how well the load is correlated with the system load; it also depends on the load factor (LF). A load with an LF close to one is likely to also have a PRF close to one. The Department estimated the distribution of PRF as a function of LF from available hourly load data. The Department used a distribution for PRF values that varies with LF. Figure 6.3.3 shows a scatterplot of PRF versus LF for hourly commercial data from the ELCAP study. The Department also examined more recent C&I hourly load data and found the results of the ELCAP data analysis to be consistent with the more recent hourly load data from the Southeast from 1998, 1999, and 2000.

The Department fit the mean value of the PRF as a function of LF to the following curve, which is also illustrated as the solid center line in Figure 6.3.3:

$$PRF_{mid} = (1 + e^{C_{PRF}})/(1+ e^{C_{PRF}/LF}) \qquad \textbf{Eq. 6.8}$$

where:

PRF_{mid}	=	the mean PFR,
C_{PRF}	=	a calibrated constant equal to 0.6, and
LF	=	the annual load factor.

The Department fit the maxima and minima of the scatterplot distribution as a function of LF using the following equations:

$$PRF_{max} = Min(1, 6 \times PRF_{mid}) \qquad \textbf{Eq. 6.9}$$

$$PRF_{min} = Max(0, PRF_{mid} - (1.2 - PRF_{mid})) \qquad \textbf{Eq. 6.10}$$

where:

PRF_{max} and PRF_{min} = the maximum and minimum PFRs, respectively,

Min	=	the function that returns the minimum of two arguments, and
Max	=	the function that returns the maximum of two arguments.

The upper and lower solid lines on Figure 6.3.3 also show the maximum and minimum bounds on the ELCAP data scatterplot, respectively.

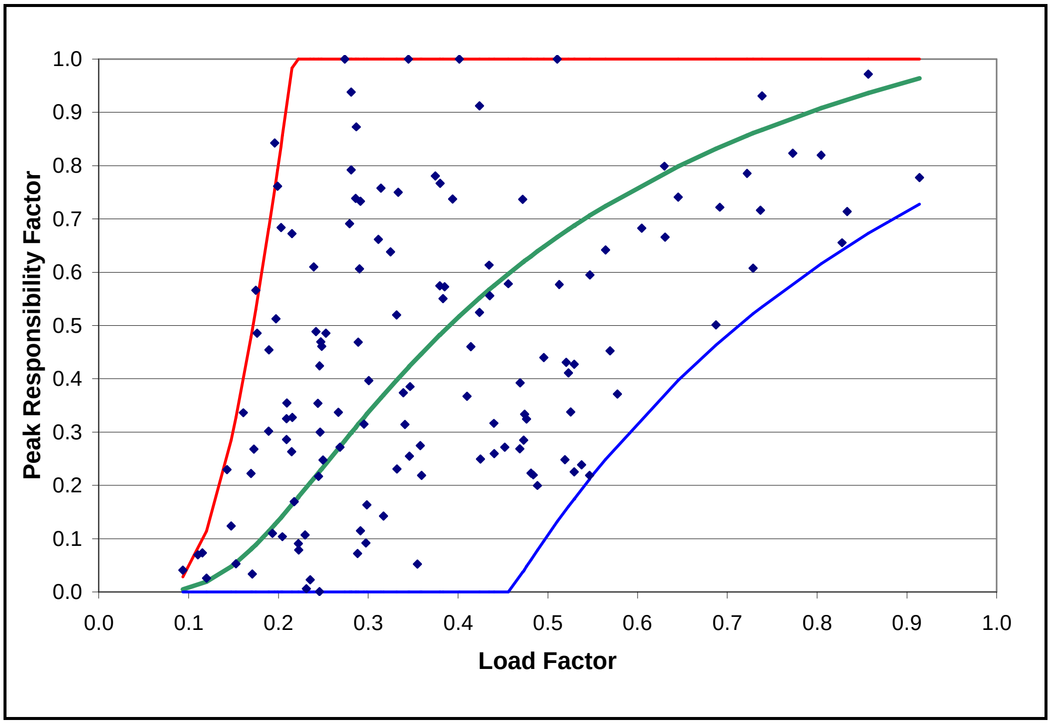

Figure 6.3.3 Scatterplot of Peak Responsibility Factor versus Load Factor

In its treatment of PRF, the Department assumed that building loads and transformer loads with the same load factor and annual peak amplitude have statistically similar behavior for the peak responsibility factor, and that industrial and commercial loads of the same average size and load factor have statistically similar behavior for the peak responsibility factor.

The Department found the aforementioned assumptions to be consistent with hourly ELCAP and proprietary utility data analyzed by the Department.

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